Control Technology Summary Table

Technology	Description	Pollutant	Typical Efficiency	Emission Limit	Capital Cost	Operating Cost	Constraints	Byproducts/ Wastes	Technology Transferability	Status	References	Other Information
Precombustion / Coal Cleaning Technologies												
Coal Cleaning		Hg SO2	0-78% 48% average		**$1,300 - $1,650/kW (2001$) (a) $1200/kW (+$200-300/kW site costs) EPRI claims this is same as for a new supercritical PC coal plant. (Rod Sobin)**				Already done on most Eastern and Mid-western coal to reduce sulfur & improve boiler performance; Hg removal varies widely-typically from 10 to 50% with mean removal rate of 21%	More advanced methods are under development	"Technology Options & Recommendations for Reducing mercury & Acid Rain Percursor Emissions from Boliers" 7/2000	

Technology	Description	Pollutant	Typical Efficiency	Emission Limit	Capital Cost	Operating Cost	Constraints	Byproducts/ Wastes	Technology Transferability	Status	References	Other Information
Combustion Technologies												
Integrated Gasification Combined Cycle (IGCC)	Feedstock is not burned directly, but is first sent to a gasifier. The gasifier breaks down coal (or any C-based feedstock) into chemical constituents prior to combustion by applying pressure, heat and steam, and controlling the stoichiometric ratios of oxygen or air. The product is called "syngas" and is primarily H, CO, and other gaseous constituents. Noncombustible impurities separate and leave through the bottom of the gasifier as slag (with minimal flyash escaping downstream). Sulfur impurities form H2S, from which S or H2SO4 is easily extracted downstream for commercial use. NOx is not generated in the gasifier's oxygen-deficient environment, and instead N reacts with H to form NH3, which can be removed from the gas stream and sold commercially for use in fertilizer products or other ammonia-based chemicals. When syngas leaves the gasifier, it is cleaned of H2S, NH3 and PM and is burned as a fuel in a combustion turbine. Exhaust heat from the combustion turbine is used in a steam generator. Use of combustion and steam turbines to generate electricity is called a combined cycle system.	NOx	**Lower firing temps. Reduce amount thermal NOx formed, but could not find exact % reduction**	**0.7 lb/MWh (a) 0.15 lb/MMBtu or 1.09 lb/MWh (b)**	**$1,300 - $1,650/kW (2001$) (a) $1200/kW (+$200-300/kW site costs) EPRI claims this is same as for a new supercritical PC coal plant. (Rod Sobin)**	**?**	**Demonstration project showed that gasifier refractory damage was incurred by frequent feedstock changes**	**H2S (commercially valuable) NH3 (commercially valuable) Slag**	**The Wabash River Project repowered a 1950s vintage pulverized coal-fired power plant with the integration of an advanced gasification system, however the gasification system and gas turbine replaced the PC boiler. Execess heat from the gas turbine was used in a heat recovery steam generator for a 1952 vintage steam turbine. Installing a gasification system is more of a ground-up boiler replacement opperation than an add-on for existing boilers.**	**Relativly New - several demonstration projects in the US**	DOE Demo Project Fact Sheets	**(See associated word document, combustion_tech_source_info.doc, for a description of data collection methods.)**
		SO2	**>97% (a) - >99% (b)**	**<0.1 lb/MMBtu (b)**								
		PM	**(a) PM emission rates 95% lower than PM from convential coal fired plants with controls.**	**<0.04 lb/MWh (a) < 0.012 lb/MMBtu (b)**								
		Lead										
		CO		**7.2 lb/hr (a) 0.05 lb/MMBtu (b)**								
		Mercury	**50% ? (a) - Half the potential release based on Hg levels in the coal. Rod Sobin wrote that the degree of removal is as much as one is willing to pay for, not limited by the technology (TN Eastman removes 96% of Hg at a gasification facility with carbon beds being replaced every 2 years).**									
		Halogens										
		HAP metals										
		Other HAPs										
Fluidized Bed Combustion	FBCs suspend solid fuels on upward-blowing jets of air during combustion, and inject a sulfur-absorbing chemical, such as limestone or dolomite into the combustion chamber to remove sulfur compounds before the tail gas exits the boiler. The turbulent mixing of gases & solids, results in more effective chemical reactions and heat transfer. There are two major categories of FBCs: (1) atmospheric (2) pressurized. Currently, atmospheric FBCs are more advanced (or commercialized) than pressurized FBCs. The two principal types of atmospheric FBCs are bubbling bed and circulating bed, which fundamentally vary in fluidization velocity. High-temperature cyclones are used in circulating FBCs and in some bubbling FBCs to capture the solid fuel and bed material for return to the primary combustion chamber. The circulating FBC maintains a continuous, high-volume recycle rate which	NOx		circulating bed: 5.0 lb/ton bubbling bead: 15.2 lb/ton	**$ 1,123/kW (net) (a)**	**$ 1,888,000 / month (a)**			**Ground-up replacement of old boilers**	**Relatively new technology, but becoming more popular and commercially available. Several current CFB projects submitted, i.e. Greene Energy**		**(See associated word document, combustion_tech_source_info.doc, for a description of data collection methods.)**
		SO2	**At bed temps. <1,620 F, SO2 capture of 70% - 90% were achieved at Ca/S ratios of 1.5 and 4.0 respectively (a) SO2 captures of 90% - 95% were achieved with Ca/S ratios of 1.14 - 1.5 respectively and a temp. of 1,580 F (b)**	SO 2 emissions for FBCs are a function of fuel S content and Ca-to- S ratio. For bubbling bed and circulating bed, use: lb SO 2 /ton coal = 39. 6(S)(Ca/ S). In this equation, S is the weight percent sulfur in the fuel and Ca/ S is the molar Ca- to-S ratio in the bed. This equation may be used when the Ca/ S is between 1.5 and 7.								

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	increases the residence time compared to the bubbling bed design. Because of this feature, circulating FBCs often achieve higher combustion efficiencies and better sorbent utilization than bubbling bed units.	PM		circulating bed: 29.4 lb/ton							**AP-42, section 1.1** **DOE Demo Project Fact Sheets**	
		Lead										
		CO		circulating bed: 18 lb/ton bubbling bead: 18 lb/ton								
		Mercury										
		Halogens										
		HAP metals										
		Other HAPs										
Low NOx Burners	New burners are installed which spread out the flame area to minimize max flame temperature	NOx	Coal - 40-60%; Oil and gas - 40-85%		$5-8 million for 350 MW plant	Low	May not be feasible in some retrofit situations	None	New burners are required. Should be applicable to most combustion sources.	Simple and requires no additonal labor		
Flue Gas Recirculation	A portion of the flue gas is recirculated as combustion air to reduce NOx	NOx	Oil and gas - 30-50%		$8-20/kW; $4 million for 350 MW plant	Low	Can cause operational difficulties with coal-fired boilers - not always applicable for coal	None	Physical modifications are required to recirculate a portion of the flue gas. Should be applicable to most combustion sources.	No additional labor required, fairly simple operation		
Low Excess Air	Limits amount of combustion air to boiler	NOx	up to 20%		$60-200/kW for retrofit, with individual SCRs as high as $165 million.	None	May not have any impact	None	Requires closer monitoring of excess air requirements; can also result in better fuel efficiency. Improvements may be needed to reduce air inleakage in heat exchange equipment.Should be applicable to most combustion sources.	Many units have been retrofit with SCR for NOx SIP call. The oxidation of mercury from SCRs is only beneficial in combination with a scrubber		
Staged Combustion	Combustion takes place in phases, with a starved-air condition in the initial flame. Additional air is added later to complete the combustion process. Limits the exposure of nitrogen from the atmosphere to flame temperatures and forces oxygen to be used for combustion instead of forming NOx.	NOx	Coal - 20-40%; Oil and gas - 10-30%		$20-60/kW	None	May not have a positive impact	None	Should be applicable to most combustion sources, as long as adequate fire box volume exists	Relatively simple operation		

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Technology	Description	Pollutant	Typical Efficiency	Emission Limit	Capital Cost	Operating Cost	Constraints	Byproducts/ Wastes	Technology Transferability	Status	References	Other Information
Post Combustion Technologies												
Electrostatic Precipitators (ESPs) (cold-side)	Charge particulates and collect on oppositely charged collector plates	PM	99.0-99.7%	0.03 lb/mm Btu 1978 NSPS	**$1,300 - $1,650/kW (2001$) (a) $1200/kW (+$200-300/kW site costs) EPRI claims this is same as for a new supercritical PC coal plant. (Rod Sobin)**						EPA-453/R-98-004a,-b "Study of HAP Emissions from Electric Utility Steam Generating Units - Final Report to Congress" (February 1998)	
		Arsenic	98%		Negligible if boiler is already equipped with ESP	Negligible if boiler is already equipped with ESP						
		Beryillium	94%									
		Cadmium	80%									
		Chromium	97%									
		Lead	93%									
		Manganese	98%									
		Mercury	25%						May be enhanced by sorbent injection			
	Pulverized coal fired boiler [bituminous]	Hg	Av. Red. 36%						Already in use for PM. Cooler temperature improves ESP performance for Hg. Hg removal efficiency found to be 42-83% on oil-fired boilers. Other references give cold-side ESP removal of mercury at a median of 15% & mean of 24% ("Technology Options & Recommendations for Reducing mercury & Acid Rain Percursor Emissions from Boliers" 7/2000)		EPA Report600/R-01-109	Table ES1; Table 3-3
		Total PM	99to 99.7%									
Electrostatic Precipitators (ESPs) (hot-side)	Charge particulates and collect on oppositely charged collector plates	PM	99.0-99.7%	0.03 lb/mm Btu 1978 NSPS	Negligible if boiler is already equipped with ESP	Negligible if boiler is already equipped with ESP					EPA-453/R-98-004a,-b "Study of HAP Emissions from Electric Utility Steam Generating Units - Final Report to Congress" (February 1998)	
		Arsenic	92%									
		Beryillium	99%									
		Cadmium	99%									
		Chromium	97%									
		Lead	97%									
		Manganese	97%									
		Mercury	0%						May be enhanced by sorbent injection			
	Pulverized coal fired boiler [bituminous]	Hg Total PM	Av. Red. 9% 99 to 99.7%			(Natural gas is typically much more expensive than coal.) $ ____/ MM Btu input					EPA Report600/R-01-109	Table ES1; Table 3-3
Enhanced ESP		Hg [0-50% at one test unit] PM 99% removal	see column C						Being developed to capture finer particles may remove more Hg. One test unit Hg removal improved with lower temperature.		"Technology Options & Recommendations for Reducing mercury & Acid Rain Percursor Emissions from Boliers" 7/2000	
Wet ESP		Hg [approx 30% in 2 pilot scale test]; PM removal 56% in pilot studies							Being investigated for "polishing" residual emissions from other controls may improve Hg removal. Lower temperature improves Hg control.	Pilot studies	"Technology Options & Recommendations for Reducing mercury & Acid Rain Percursor Emissions from Boliers" 7/2000	
Non-Thermal Plasma	Electro-Catalytic Oxidation (ECO) utilizes a barrier discharge to oxidize pollutants to be captured by a wet ESP that also collects PM	Hg >80%							Currently in demonstration project stage		"Control Technology: Non-Thermal Plasma Based Removal of Mercury"	First Energy's R.E.Burger Generating Station
Fabric Filtration (Baghouses)	Particulates collected on a fabric bag	PM	99.0-99.9%	0.03 lb/mm Btu 1978 NSPS							EPA-453/R-98-004a,-b "Study of HAP Emissions from Electric Utility Steam Generating Units - Final Report to Congress" (February 1998)	
		Arsenic	99%		Negligible if boiler is already equipped with fabric filter	Negligible if boiler is already equipped with fabric filter						
		Beryillium	99%									
		Cadmium	72%									
		Chromium	94%									
		Lead	99%									
		Manganese	98%									
		Mercury	36%						May be enhanced by sorbent injection			
	Pulverized coal fired boiler [bituminous]	Hg Total PM	Av. Red. 90% 99 to 99.9%						Lower temperatures appear to improve performance.		EPA Report600/R-01-109	Table ES1; Table 3-3

Control Technology Summary Table

Technology	Description	Pollutant	Typical Efficiency	Emission Limit	Capital Cost	Operating Cost	Constraints	Byproducts/ Wastes	Technology Transferability	Status	References	Other Information
Selective Catalytic Reduction (SCR)	Use of Selective Catalytic Reduction NOx control enhances oxidation of Hg0 in flue gas and results in increased mercury removal in wet FGD In general, the amount of Hg captured by a given control technology is greater for bituminous coal than for either subbituminous coal or lignite. Existing control remove about 36% of the 75 tons of mercury input with coal in US coal fired boilers, about 48 tons of Hg.	NOx Hg NOx Hg PM2.5	97% 80%-90% 98% when SCR used with SDA and FF 95% reduction in Hg emissions by SCR along with a scrubber		\$60-200/kW for retrofit, with individual SCRs as high as \$165 million.	\$1,602/ton of NOx removed (1977 dollars) Hg and NOx comparison Total annual cost 0.18 - 1.15 mills/kWh - Hg 1.85 - 3.62 mills/kWh - SCR 0.21 - 0.83 mills/kWh - low NOx burners			Analysis showed coal fired units as predominant candidates for NOx control technologies accounting for 940K tons or 98% of total NOx reduction requirements Oxidation of elemental Hg by SCR catalyst may be affected by the space velocity of catalyst, temperature of the reaction, the concentration of NH3, age of the catalyst, and concentration of chlorine in the gas stream. Field testing by 6 coal fired power plants in 2001 showed that while oxidation of Hg across SCR systems can occur, it is a complex proces that may be dependent on several variable such as coal properties, furnace combustion conditions, and SCR catalyst factors including type, sizing, and age.	Many units have been retrofit with SCR for NOx SIP call. The oxidation of mercury from SCRs is only beneficial in combination with a scrubber	Mann and Ramesan, DOE, Ward - SAIC Angelo Proestos, Cheminfo USEPA Office of R&D, Air Pollution Prevneton and Control Division, RTP, NC Northeast States for Coordinated Air Use Management Report on Hg Emissions from Coal Fired Power Plants, October 2003 Michael Rossler, The Electric Power Industry and Mercury Regulation USDOE/NETL Hg Control Technology Program for Coal Fired Power Plants, April 2003	Multipollutant removal by SCR and Wet FGD: The speciation of mercury has a significatn impact on the ability of control equipment. The oxidized form of Hg, HgCl2 is highly water soluble. SCR catalysts can act to oxidize a significant portion of the Hg0 enhancing the capture of Hg in downstream wet FGD.
Selective Non-Catalytic Reduction (SNCR)	Ammonia or urea injected to react with NOx to form elemental nitrogen and oxygen. No catalyst used	NOx Hg NOx Hg PM2.5	Remaining 3% 30%-50%		\$20-60/kW						Mann and Ramesan, DOE, Ward - SAIC Angelo Proestos, Cheminfo	
Wet Scrubbers (represent 83% of current US-installed FGD capacity)	Flue Gas Desulfurization using limestone or lime	SO2	96.3	0.15 lb/mmBtu with 2.5% S coal	Continuring to decrease	Energy requirement have cont to decrease lowering operating costs		wet slurry > gypsum w add trt			permit issued, Oct 2002	Coal Survey by Don Shepherd, NPS
		SO2	97.9	0.167 lb/mmBtu with 4.2% S coal							permit issued, Mar 2005	Coal Survey by Don Shepherd, NPS
		HCl	95+									www.icac.com
		HF	>33									www.icac.com
		Heavy metals	significant									www.icac.com
		Hg	97%									www.icac.com
		>90% oxidized Hg; 0-70% elemental Hg 80-90% SO2	see column C						Already in use to reduce SO2. Effectiveness for Hg removal is highly dependent on mix of chemical species present & other factors including liquid-to-gas ratio, chlorine content & coal type		"Technology Options & Recommendations for Reducing mercury & Acid Rain Percursor Emissions from Boliers" 7/2000	
Dry Scrubbers	Flue Gas Desulfurization using dry lime injection	SO2	West 83.1	0.329 lb/mmBtu with 0.65% S coal	Generally lower than spray drying scrubbers	Higher operating costs than spray drying scrubbers		gypsum			operating, permit issued 1986	Coal Survey by Don Shepherd, NPS
	Flue Gas Desulfurization using lime spray drying	SO2	93.7	0.162 lb/mmBtu with 1.3% S coal	Less than wet scrubbers	Less than wet scrubbers		gypsum			permit issued, Jan 2001	Coal Survey by Don Shepherd, NPS
		Heavy metals										
		Hg										
		Hg 6-96% [With recent studies 63%] SO2 80-90%	see column C						Only found in 1% of US boilers; removal efficiency for Hg depends on speciation, temperature & chlorine content . Lime scrubbers show better Hg removal in pilot tests		"Technology Options & Recommendations for Reducing mercury & Acid Rain Percursor Emissions from Boliers" 7/2000	

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Multiple Pollutant Technologies												
Fabric Filter & Spray Dryer Adsorber	Pulverized coal fired boiler [bituminous]	Hg	Av. Reduction 98%		**$1,300 - $1,650/kW (2001$) (a) $1200/kW (+$200-300/kW site costs) EPRI claims this is same as for a new supercritical PC coal plant. (Rod Sobin)**						EPA Report600/R-01-109	Table ES1;
Fabric Filter & Spray Dryer Adsorber & Selectic Catalytic Reduction	Pulverized coal fired boiler [bituminous]	Hg	Av. Reduction 98%								EPA Report600/R-01-109	Table ES1;
Particulate Scrubber Wet Flue Gas Desulfurization	Pulverized coal fired boiler [bituminous]	Hg Total PM	Av. Red. 12% 95 to 99%								EPA Report600/R-01-109	Table ES1; Table 3-3
Cold side -ESP & Wet Flue Gas Desulfurization	Pulverized coal fired boiler [bituminous]	Hg	Av. Reduction 75%								EPA Report600/R-01-109	Table ES1;
Hot side - ESP & Wet Flue Gas Desulfurization	Pulverized coal fired boiler [bituminous]	Hg	Av. Reduction 49%								EPA Report600/R-01-109	Table ES1;
Fabric Filter & Wet Flue Gas Desulfurization	Pulverized coal fired boiler [bituminous]	Hg	Av. Reduction 98%							Limited data - based on two short term tests	EPA Report600/R-01-109	Table ES1;
Combined SCR & Wet Scrubber		Hg SOx NOx	50-80% 90+% 90+%						Already in use to reduce Nox helps convert Hg to soluble, oxidized form, thereby allowingfor grreater removal by downstream wet scrubber	Limited data	"Technology Options & Recommendations for Reducing mercury & Acid Rain Percursor Emissions from Boliers" 7/2000	
Combined ESP/Baghouse		Hg [34-87% in 2 pilot facilities]; PM removal >99.9%							Combination technology to achieve very low PM emissions can improve removal of Hg & other toxics. EPRI's COHPAC version with carbon adsorption (TOXECON} provided reductions up to 90%.	Pilot studies	"Technology Options & Recommendations for Reducing mercury & Acid Rain Percursor Emissions from Boliers" 7/2000	
ISCA [post combustion emission control system]	Chemical Oxidation- gas phase oxidation process	SOx NOx Hg	99% 98% > 99%					Saleable acid products from pollution process control system		bench scale	ISCA Fact Sheet & Management Information	

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Additives/ Sorbents												
Sodium Tetrasulfide (Na2S4)	Injected Upstream of a Baghouse (270 F)- Bituminous Coal	Hg	90% reduction		**$1,300 - $1,650/kW (2001$) (a) $1200/kW (+$200-300/kW site costs) EPRI claims this is same as for a new supercritical PC coal plant. (Rod Sobin)**				used in a number of waste-to-energy plants	Pilot Tested at Babcock Power, MA	ICAC Forum 03 Report: Coal-Fired Power Plant Mercury Control by Injecting Sodium Tetrasulfide	Process has been used in waste to energy plants
Amended Silicate	configured with a reverse-gas baghouse PM control module; Powder River Basin Coal	Hg	70 to 96% reduction						may not impact fly ash sales	Pilot Tested at Xcel Energy's Comanche Station Unit 2	"Evaluation of Amended Silicate Sprbents for Mercury Control"	
Remedia Catalytic Filter System	Incorporated into pulse-jet baghouse fabric filters	Hg	70 to 96% reduction							Bench scale tests	"A Novel Technology to Immobilize mercury from Flue Gases"	
MerCAP (Mercury Control Adsorption Processes) gold-coated plates	can be retrofitted into existing ductwork, baghouse or ESP casing, or stack	Hg	>80%		with 90% control- 3 month regeneration & 100% redundancy is est. at $4.7million for 250MW unit ($18.8/kW) [$2.3 million is gold media & substrate]; 1 year regeneration & lower mercury capacity est. at $14.9 million for 250MW unit ($59/kW) [$12.6 million for gold media and substrate] ; levelized costs from 1.4 to 2.9 mills/kWh				can be added to existing PM and/or SO2 controls	Pilot tested	"Development and Demonstration of Mercury Control by Adsorption Processes (MerCAP)	periodicaly regnerate to recover Hg
Additive injection upstream of limestone, forced oxidation wet FGD system	[high sulfur, eastern bituminous]	Hg	77% [average removal short-term test]			cost estimate of variable additive cost (equipment already present) .18mills/kWh	injection rate 1 gal/hr			short-term test	NETL Project & report	Michigan South Central Power Agency [Endicott/Litchfield,MI]
Additive injection upstream of magnesium-enhanced lime with ex-situ oxidation wet FGD system	[high sulfur, eastern bituminous]	Hg	51% [average removal short-term test]			cost estimate of variable additive cost (equipment already present) .18-.23mills/kWh	injection rate 27 gal/hr			short-term test	NETL Project & report	Cinergy [Zimmer/Moscow, OH]
Sorbent- Powered Activated Carbon [PAC] injection upstream of Compact Hybrid Particulate Collector (COHPAC) baghouse; TOXECON when sorbent such as AC is injected upstream of COHPAC baghouse downstream of an ESP	[low sulfur, eastern bituminous]	Hg	87% [average removal short-term test]; with ESP 60 to 70 % removal; with FF up to 90% removal		est. minimal capital costs of equipment <$3/kW; 100 to 500 MW plant to add PAC injection equipment $600,000 to $1000000; installing FF cost $40 to $50/kW but reduces sorbent use up to factor of 3	cost estimate of variable additive cost (equipment already present) .3-.5 mills/kWh; with ESP sorbent costs approx. 1.2 mills/kWh; with FF 0.4 mills/kWh	costs & effectiveness vary with type of coal, flue gas temperature/unburned carbon levels, sorbent injection rate, activated carbon type and between plants with ESPs versus FFs; if all plants used PAC, there might initially be a shortage of supply	mercury in fly ash maybe/may not be a problem; COHPAC & TOXECON combined removes ash upstream of PAC injection and remains acceptable for sale		short-term test	NETL Project & report; ICAC Forum 03 Report "Full-Scale Results of Mercury Control by Injecting Activated Carbon Upstream of ESPs and Fabric Filters;Performance & Costs of Mercury Control Technology for Bituminous Coals by Michael D. Durham on 4/20/04	Southern Company [Gaston/Wilsonville, AL]
Pahlman sorbent [oxide of manganese]; fabric filter baghouse serves as "reaction chamber"		SOx NOx Hg PM	>99% >0.01lbs./MMBtu 95% >0.002lbs./MMBtu			est. O & M costs up to 30 % less [vs. wet FGD & SCR systems]		fly ash removed prior to Pahlman Process control		pilot test	enviroscrub Technologies Corp. brochure	
Corona Discharge	ionization of air by high voltage electrical discharge in bolier flue upstream of an ESP & wet scrubber; increased SO3 improves collection of PM acts to convert Hg0 to Hg2+ that can be captured by alkalineFGD scrubber downstream	Hg	80%							bench; piolt test at Alabama Power Miller Plant (Unit 3)	"Control of Mercury Emissions from Coal-Fired Electric Utility Boilers:Interim Report", 4/2002	
Electro-catalytic Oxidation										bench		

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Electron Beam Irradiation	identical to corona discharge except power source is battery of irradiating electron "guns" & oxidation products enter semi-dryabsorption system with ammonia reagent & converted to ammonium sulfate & nitrate salts [usable for fertilizer];							presumed Hg will be in fertilizer as contaminants	Used in Japan & China; available commercially since 1980s	bench		
Direct Injection of Oxidizing Agents into Flue Gas										bench		
Circulating Fluidized Beds (CFBs)	Use activated carbon (AC) in CFB. AC is continuously fed to reactor where mixed with flue gas at relatively high velocity, separated in FF & recycled to reactor								currently used at waste incinerators in Europe and gasification units in US			
Circulating bed of Fly Ash	fly ash & activated carbon-based technology with ESP and lime for SO2 removal	Hg	80% Hg vapor							test	"Pollution Engineering" archives/2000/pol0201.00/po10200news.htm	PSE&G Mercer Generating Station
Mobotec System mulit-polluntant reduction technology	Uses ROFA and Rotomix systems; compared use of injection of limestone & trona	**trona**- SO2 reduction 69%, SO3 90%, HCL 75%, Nox 11%, PM 80% & Hg 67%; **limestone**- SO2 redcution 64%, SO3 90%, HCL 0%, Nox 4&, PM 18% & Hg 89%	see column C				Excessive slagging occurred on superheater tubes requiring shut down to remove slag			test	"Full-Scale Evaluation of a Multi-Pollutant Reduction Technology: SO2,Hg and Nox MobotecUSA, Inc. for Presentation at ICAC's Forum '03"	Cape Fear Power Station
Zeolite catalysts		Hg	45-92%					aluminosilicate sorbents should not degrade fly ashes used as a substitute for cement in concrete or filler in plastics		bench	"Status review of mercury control options for coal-fired power plants" 2003	

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